Chevron

Lisa B. Barry
Vice President and
General Manager

Policy, Government and Public Affairs
Chevron Government Affairs
1401 Eye Street, NW
Suite 1200
Washington, DC 20005
Tel 202 408 5800
Fax 202 408 5845
lbbarry@chevron.com

June 22, 2005

Mr. Mark Friedrichs
Policy Analyst
U.S. Department of Energy
PI-40/Forrestal Building
1000 Independence Avenue, S.W.
Washington, DC 20585

Dear Mr. Friedrichs:

Chevron appreciates the Department of Energy's (DOE) efforts in holding public meetings and taking comments on the Interim Final Rule for the revised General Guidelines for Voluntary Greenhouse Gas Reporting (General Guidelines) and the draft Technical Guidelines (RIN Number 1901-AB11). We are pleased to provide comments and recognize the need for a greenhouse gas (GHG) reporting system that is accurate, reliable and verifiable in order to demonstrate achievement of the President's GHG intensity reduction goal. A national system is essential for consistency and to avoid a patchwork of local, state and regional systems that would complicate reporting for large companies operating in several areas throughout the U.S.

Chevron is an integrated energy company, involved in every aspect of the energy industry. Our operations range from oil and gas exploration and production to transportation, refining and retail marketing, as well as chemicals manufacturing and sales and power production. Chevron is an environmentally responsible company and recognizes and shares the concerns that governments and the public have about climate change. We have developed a comprehensive program to manage greenhouse gas emissions, and it is being integrated into our business decisions.

Chevron has a practical understanding of GHG reporting issues through direct experience in several areas. First, we estimate our greenhouse gas emissions using the American Petroleum Institute's (API) SANGEA™ Energy and Emissions Estimating System. We recently completed a successful third-party verification of our 2002 and 2003 inventory. Second, we have reported selected projects in the 1605(b) program since 2000. And third, we Chair the API Greenhouse Gas Emissions Estimating Work Group that developed the Compendium of Greenhouse Gas Emissions Estimation Methodologies for the Oil and Gas Industry. We also support the DOE in developing a program that encourages broad, entity-wide participation to reach the President's GHG reduction goal.

We took a leadership role in the development of API's comments and support those that are submitted. Also attached are Chevron's comments reinforcing key overarching issues followed by detailed comments on the Technical Guidelines. We acknowledge the amount of effort it takes to create a national reporting system and appreciate the consideration of our previous comments in both 2002 and 2004. We hope that these comments are helpful in finalizing the general reporting and technical guidelines. If you have any questions, please do not hesitate to contact Judy Blanchard in my office at (202) 408-5831.

Regards,

Lisa B. Barry

KJD/Enclosure

GENERAL GUIDELINES KEY ISSUES

Chevron supports the DOE's determination of the following issues:

- **Flexible definition of "entity"**
Flexibility allows entities to determine how to best aggregate their business units (pages 32, 57, and 65), potentially phase in the reporting and get registered reductions. It will also allow the option for reporting distinct sectors within the industry, such as refining and production. However, we note that the original Guidelines and now the final Guidelines both require a reporting entity to be a "legal" entity. In order to provide the desired level of flexibility, we recommend that the standing definition be tied to something less stringent than a legal entity. For example, the definition could be modified to include divisions of a legal entity which are not themselves legal entities *(i.e.* corporations, subsidiaries, etc.).

- **Permission to trade, sell or otherwise transfer registered emission reductions**
It is appropriate for DOE to allow entities to trade, sell or transfer registered emission reductions. As activities related to registered emission reductions increase, the parties involved in DOE's voluntary program will benefit from flexibility in trading, selling or otherwise transferring the registered reductions as needed.

- **Ability to register offsets**
Use of offsets enables participating entities to achieve emissions reductions in a cost-effective manner.

- **Optional registration of non-U.S. emissions**
DOE's acceptance and encouragement of voluntary reporting and registration of non-US emissions and emission reductions is appropriate, given that climate change is a global concern. We support DOE's guidance that voluntary international emissions data may be reported along with, but separate from, the U.S. data, and may be eligible for registration.

- **Reference to the American Petroleum Institute (API) Compendium and SANGEA™ Emissions Estimating System as part of the inventory guidance**
We appreciate DOE's support for using the Compendium's methodology for the oil and gas industry and other industry sectors at large. DOE should also recognize the availability of API's SANGEA™ Energy and Emissions Estimating System spreadsheet tool. API will keep the Compendium and the spreadsheet tool up to date, and we recommend that DOE incorporate a reference to the latest versions of the Compendium and spreadsheet tool to assist inventory preparers. The SANGEA™ system is available free of charge at http://projects.battelle.org/sangea/home.asp

- **Report certification signature by responsible officer (other than the CEO)**
We appreciate DOE's acknowledgement that the position of chief executive officer is not appropriate for report certification. The management position responsible for reporting the entity's compliance with environmental regulations or other position designated as the certifier is a more appropriate sign-off level. For project-specific reporting of emissions, emissions reductions, offsets, or carbon sequestration, a project manager's signature should also be deemed as the appropriate sign-off level. This would be consistent with practice under the current 1605b program.

Suggested Revisions/Comments

- **Enable companies to substitute third-party verification in place of the proposed emissions rating system**. As DOE may be aware, several companies have already developed voluntary inventory programs using globally acceptable protocols, and have made a significant effort to verify the transparency, accuracy, consistency and credibility of their inventories by engaging reputable third-party verifiers These efforts should be acknowledged as equivalent, if not superior to, the proposed emissions rating system, since involvement of a third-party verifier is the benchmark standard for the auditing of financial statements. Furthermore, emissions inventory verifications can be conducted utilizing financial principles, and increasingly are conducted using the recently issued International Standard on Assurance Engagements (ISAE) 3000 Assurance Standard for Non-Financial Reviews. Chevron's own direct experience of commissioning a third-party verification by KPMG and URS lead us to the conclusion that such efforts are rigorous and provides the needed transparency, accuracy, consistency and credibility characteristics that are equivalent to the rigor of financial auditing. For details of the Chevron third-party verification experience, we incorporate by reference the following web link: http://www.chevron.com/social_responsibility/environment/greenhouse_gas.asp

- **If the emissions rating system is required, some of the factors should be reviewed**. For example, the emissions rating system assigns too low a rating, *a C rating*, for "default emission factors based on general activity data." Many sectors use the default factors approach (such as in the API Compendium) and it would take considerable resources to develop entity-specific factors. For this reason, the use of default factors should be recognized as appropriate and sufficient and also given the highest rating, *an A rating*, as is done with the agriculture and forestry sectors.

- **We recommend using a 5% (vs. 3%) de minimus reporting level because it is more consistent with financial accounting practices and other greenhouse gas emissions reporting programs such as the EPA Climate Leaders, EU Emissions Trading Scheme and the California Climate Action Registry (CCAR)**. Chevron agrees with using a fixed percentage for determining de minimus levels because it makes good, practical sense. Our experience is that accounting for emissions from sources that total less than 5% of total emissions requires a significant amount of effort. This can be discouraging since the benefit of accounting for very low levels of emissions is often outweighed by the costs.

- **Many companies have established emissions management programs over the last few years and they should be able to translate their work directly into the DOE program without mobilizing extra resources**. We would like to see the DOE continue to recognize and encourage voluntary actions by allowing flexibility in the timing of emissions reporting where appropriate. For example, if an entity chooses to initiate a 3rd party verification of their inventory, we advise not placing an annual time limit for doing so. It is more cost effective to review multiple reporting years simultaneously so an entity may do the verifications every two to three years. Also, there should be some provision for obtaining an extension or circumstances under which late reporting is permissible, particularly if DOE review/response takes more than 6 months and DOE comments provoke revision of inventory. Furthermore, if a major business change such as a merger occurs, it may take additional time to understand and incorporate all the new sources (pages 78, 83, 90). This is implied on page 91 but should be made clear.

- **<u>Minor clarifications</u>**

    - Page 88 implies that onsite 3rd party reviews are needed only if an entity has widely dispersed operations. Onsite reviews would be needed for most large operations regardless of "dispersion" of operations.
    - Page 23 does not clearly state that "capture and sell greenhouse gases" refers only to carbon dioxide that would normally be released to the atmosphere and does not include methane in natural gas or other products intended for sale.

TECHNICAL GUIDELINES KEY ISSUES

- **<u>Cost-effectiveness</u>**
  We strongly agree with the bullet point titled "Cost and Feasibility", which states that some methods may be costly and others infeasible. This is further reason that DOE should allow entities to utilize third-party verification in lieu of the emissions rating system, enable a multi-year reporting/verification program, institute a 5% de minimus level, commensurate with other inventory programs and avoid over-reliance on Continuous Emissions Monitors (CEMs, see below).

- **<u>Mass Balance more cost-effective than continuous emissions monitors (CEMs)</u>**
  For many entities and sources, CEMs will not always be cost-effective, and may not significantly improve the quality of the inventories. Many industries, including refineries and production facilities, combust fuels at multiple small sources and do not have continuous emissions monitors. DOE should promote accuracy by providing flexibility to the data reporter by allowing estimates based on accurate and timely estimates of fuel composition and utilization rate. At times, when continuous emissions monitors are more cost-effective for specific centralized applications, the DOE should allow for that. Emissions from combustion can be accurately estimated based on fuel composition and utilization rate. The accuracy of CEMS would depend highly on the calibration process. Both methodologies can be cost effective, depending on the configuration of the facility, the variations of fuels combusted, and the number of stacks for the exhaust gases.

- **<u>Assume 100% conversion of carbon to carbon dioxide in combustion processes</u>**
  As per the API Compendium, an accurate, conservative emissions inventory can be developed more cost-effectively and transparently if combustion is assumed complete for the purpose of carbon dioxide emissions estimating. Entities still can and should estimate (or demonstrate de minimus) emissions of unburned methane; this does not represent double-counting, since the unburned fuel eventually oxidizes to carbon dioxide in the atmosphere.

- **<u>Improve rating for hydrogen plant mass balance</u>**
  Estimates of hydrogen plant emissions based on mass balance should receive a rating of "A" since this is the preferred approach in the API Compendium and can achieve accuracy of 95% or higher (page 92).

- **API Compendium more appropriate than IPCC National Guidelines for Entity Reporting**.
  The methodologies in the API Compendium should be the first recommendation for petroleum industry reporting in the DOE program since these methodologies were developed specifically for industrial reporting. In contrast, the IPCC Guidelines are designed from the perspective of reporting from a national government, rather than reporting from an industrial facility (page 110).

- **Enable technical needs to set sequestration reporting criteria.** Since the technology and monitoring methodologies for carbon sequestration are relatively new, this is an opportunity for DOE to harmonize its guidance with emerging worldwide practices in this area. Furthermore, unlike entity-based inventories, carbon sequestration project inventories are appropriately handled in a similar manner for both project reporting in the DOE program and national inventory development under IPCC auspices. Although we generally recommend against application of the IPCC National Inventory Guidelines to entity-based reporting, we strongly suggest that DOE refer to the IPCC Special Report on Carbon Sequestration and the 2006 IPCC Guidelines for National Greenhouse Gas Inventories, Volume 2, Chapter 5, and set up the reporting program such that technical drivers for carbon sequestration projects set the basis for emission reporting.

- **Clarify carbon dioxide streams that may be eligible for registered emission reductions.** We would appreciate if DOE could clarify that if carbon dioxide used for enhanced oil recovery would otherwise have been vented, the project should be permitted to be registered as an emissions reduction. For example, carbon dioxide for enhanced recovery may be obtained from a hydrogen manufacturing plant's vent stack instead of recovering it from underground reserves. As another example, carbon dioxide separated as a contaminant during production of industrial gases such as helium is normally vented. If the carbon dioxide is recovered and used for enhanced oil recovery, this would represent an emissions reduction (page 157, 3rd paragraph). The emissions reduction will be the net CO_2 remaining in the reservoir at the end of the project. Appropriate methodologies for generating an annual reduction number can be generated as the project progresses.

- **Carbon dioxide emissions reporting requirements should be based on the project permit.** Excessive monitoring of carbon sequestration projects just for the purpose of reporting to the DOE program would be burdensome for reporters. Monitoring requirements for carbon dioxide sequestration projects should be established based on technical, site-specific needs, as agreed by the project proponent and responsible regulatory agency. Emissions reduction reporting requirements should follow from the agreed monitoring requirements. Note that most monitoring efforts are directed to identifying the location of CO_2 for safety, emissions, or process purposes. Mass balance approaches coupled with reservoir integrity monitoring (mass in minus mass out coupled with an assessment of whether any leakage is present) are likely to be the most positive way to encourage sequestration.

Additional Comments/Issues

- Page 9: Global Warming Potentials (GWPs) differ from the Second Assessment Report (SAR). We recommend that DOE use the GWPs from the SAR through 2012 which is consistent with international practice.

- Page 15, section 1.B.3.2 (1st sentence): Water vapor is actually the most common greenhouse gas; carbon dioxide is the most common anthropogenic greenhouse gas.

- Page 16: The term 'Waste combustion' is not really appropriate. Flaring and Coke burn are two different activities. Flaring is mainly relied on for emergency relief purposes. Coke burn is an integral part of the catalytic cracking process, and process equipment is designed to recover heat from this combustion process.

- Page 31, Section 1.B.4.4, 1.B.4.5 and 1.B.4.6: This information is not really relevant for the DOE reporting program. Particularly in section 1.B.4.5, DOE appears to be significantly underestimating the amount of effort required by an entity to develop and submit technically sound, valid inventory information every year.

- Page 35: The "Mass Balance" approach is the preferred approach for estimating combustion emissions, and also can be effective in estimating emissions based on volume and/or heating value of the fuel.

- Page 41, Table 1.C.6: The basis for heating value should be specified (high heating value or low heating value). It appears that this table is based on higher heating value.

- Page 43 Table 1.C.9: Emissions based on a Mass Balance with default emission factors for fuel gas or liquid petroleum gas should receive a rating of A since the composition is unlikely to change sufficiently to materially affect emissions from combustion.

- Page 46, 1st paragraph: Since refinery fuel gas is no more hazardous than natural gas, it is inappropriate to characterize it as an "explosive safety hazard to be controlled." Furthermore, this assertion is irrelevant to the greenhouse gas reporting program.

- Page 46, 1st bullet: Refinery gas is not a waste product.

- Page 49: Emissions estimates for venting and flaring achieved by estimating the venting or flaring rate, with actual composition data from periodic samples should be given a rating of "A."

- Pages 74 and 79: Include a reference to the most recent version of the Compendium (February 2004) and the SANGEA™ Energy and Emissions Estimating System web site. http://projects.battelle.org/sangea/home.asp

- Page 108, 1st and 2nd paragraphs: The text indicates that the majority of emissions from oil and gas production are fugitive emissions. Most emissions from production are due to fuel combustion. Industry has been working to control methane emissions, and these are very small compared to carbon dioxide.

- Page 108, 3rd paragraph: Carbon dioxide is only emitted from sour gas processing if there is carbon dioxide in the gas coming from the reservoir. Nitrous oxide is only emitted from combustion activities in the petroleum industry, so the statement that it is emitted from 'a number of activities' is misleading (Please refer to API Compendium Tables 2-2 through 2-8).

- Page 109, Table 1.E.2.5: The petroleum industry does not currently divide operations into the same categories as IPCC. Please refer to the API Reporting Guidelines for industry sub sectors. As noted above IPCC guidelines for National inventories are not typically appropriate for 'bottom up' entity reporting.

- Page 109: The comprehensive approach described will not be cost-effective and will not be significantly more accurate than current approaches.

- Page 111, 1st paragraph: It is neither cost-effective nor feasible to directly measure equipment leaks and losses. Concentration measurements of fugitive emissions can be made, but converting the concentrations into quantifiable emissions is not a straightforward process.

- Page 112, Table 1.E.26: A mass balance approach should be given a rating of "A" since direct, site-specific measurements for carbon dioxide and methane emissions are not feasible.

- Page 135, last paragraph: It is misleading to say that carbon dioxide "is usually leaked." It would be better to say that "trace amounts of fugitive emissions may occur."

- Page 138: At some facilities, transmission losses are already accounted for in the net electricity sold. On page 138, a transmission loss adjustment factor is included to make the supplier responsible for these emissions. However if sales records are used, the line loss may already be accounted for (at least if it is sold to the grid). Some companies, such as Pacific Gas and Electric (PG&E) and Southern California Edison (SCE), have line loss factors that accounting and finance groups incorporate into the total electricity sold. Therefore, it should be noted in the Technical Guidelines that this factor may have already been accounted for, and if so, should not be used again in the calculation.

- Page 139 Table 1.F.1: The 1998-2000 averages are nearly five years old. DOE should specify how and when these will be updated, and should provide guidelines for reporters in updating their inventories. For example, it may be cost-effective for reporters to update electricity emission factors every two or three years. This should provide reasonable accuracy, since grid electricity factors are not expected to change rapidly.

- Page 145, section 1.F.2.7: Please clarify how this applies to a facility that generates electricity. In some cases, a facility may be a net importer of electricity in one year, and a net exporter the next year, depending on facility electrical needs and on-site generation capacity. There should be a provision for reporting both when electricity is imported and when it is exported.

- Pages 146 and 148: The DOE allows for use of purchase records only if there is not internal metering within the organization. DOE should consider using purchase records as the preferred method. Since both parties (the supplier and the user) agree on the amount of electricity or steam purchased, the use of this value will allow for consistency in calculating the greenhouse gases. If the user is stating in his report that they consumed x CO_2 eq. tonnes of electricity, we want the supplier to get credit for having sold x CO_2 eq. tonnes of electricity. If both organizations used their own internal meters, the numbers most likely will not agree.

- Page 148: Application of an "A" rating to default regional or default national emission rates is inconsistent with lower ratings applied to default factors in other sections, such as combustion.

- Page 152: The DOE states that "before estimating emissions from individual heat or electricity purchases, reporters need to know the total quantities of the fuel used and thermal and electrical power generated by the CHP." Customers do not typically receive these figures directly from the suppliers. DOE should consider that most of these customers will use averages or default values, which will undermine consistency between customer and supplier.

- Page 153: Assumption of 80% efficiency for steam generation may not be appropriate in all cases and will lead to overestimation of emissions associated with electricity from cogeneration facilities. This approach is also inconsistent with that used in the WRI/WBCSD, UK Emissions Trading System and the approaches recommended in the Petroleum Industry Guidelines for Estimating Greenhouse Gas Emissions. DOE should have further discussions with cogeneration facility operators to determine a meaningful, common, cost-effective approach.

- Page 154, ratings: The ratings assessment for electricity from cogeneration facilities is inappropriately more rigorous than that from other electricity types. A less rigorous assessment should be permitted, in order to encourage cogeneration facility operators to report emission reductions.

- Page 157, 3rd paragraph: If carbon dioxide used for enhanced oil recovery would otherwise have been vented, sequestration should be allowed to be registered as an emissions reduction. For example, carbon dioxide for enhanced recovery may be obtained from a hydrogen manufacturing plant's vent stack. As another example, carbon dioxide separated as a contaminant during production of industrial gases such as helium is normally vented. If the carbon dioxide is recovered and used for enhanced oil recovery, this would represent an emissions reduction. Net emission reduction will be that portion of the total annual volume injected that is expected to remain in the reservoir under the current operating plan.

- Page 160: Item "c" in the list of alternatives should be placed first, and item "a" should be last since item "c" is preferable and more common.

- Page 161, 1st paragraph: The API Compendium is a better reference for estimating fugitive emissions, and should be recommended as the preferred method.

- Page 162, 1st and 2nd paragraph: It is not possible to measure the amount of carbon dioxide in the reservoir, either before or after withdrawal. A flow meter cannot be used to measure the amount of carbon dioxide lost from a reservoir.

- Page 162 Section 1.G.5.2, 2nd paragraph: Consider editing the following sentence to make it clearer: "Arriving at the correct inventory of emissions after capture may involve some subtraction to determine the correct amount of carbon dioxide emitted."

- Page 163, Section 1.G.5.3, Equation 4: It is not possible to measure pipeline input and endpoint accurately enough to discern fugitive emissions. As noted above, DOE should seek to harmonize its guidance with recent IPCC publications on carbon dioxide sequestration.

- Page 165, equation 7: A variable appears to be missing from the equation -- the number of components should be part of this calculation.

- Page 165, equation 8: It is not possible to measure the amount of carbon dioxide in storage at the beginning or end of a given reporting period, and certainly not with sufficient accuracy to characterize fugitive emissions. Fugitive emissions will most likely be well under the de minimus level for carbon sequestration projects.

- Page 166, Section 1.G.7: The monitoring discussion seems to be very optimistic about monitoring capabilities. First, the discussion seems to focus on the operating period of the reservoir. As suggested in the IPCC Guidelines, monitoring guidelines are needed for the life of the reservoir. Also, there seems to be an assumption that what leaks out of the primary reservoir reaches the atmosphere. This is not necessarily true, since some CO_2 may only migrate to other layers within the reservoir or overlying strata. Finally, the requirement for "at least annual" application of at least two of the given subsurface direct measurement techniques will be discouraging if implemented as written since it could increase the project cost, often with very limited operational benefit or change in signal to be measured. Note that the primary monitoring technique for natural gas storage, deep waste injection, and acid gas disposal is measurement of well pressures and flow/injection rates (if any). The operating pressures and flow rates are measured at least quasi-continuously, so that basic reservoir performance monitoring at this level is frequent. This should be the case for CO_2 storage as well.

  The first paragraph states that current monitoring indicates that physical leakage rates are small at current storage sites yet the second paragraph mandates far more monitoring than is currently done but does not focus on surface seepage measurements. Excessive monitoring will be burdensome for reporters. Monitoring requirements for carbon dioxide sequestration projects should be established based on technical, site-specific needs, as agreed by the project proponent and responsible regulatory agency. Emissions reduction reporting requirements should follow from the agreed monitoring requirements. Several technical points are provided below to illustrate why site-specific, technology-driven monitoring plans should be the primary means of monitoring sequestration projects. These comments reflect the current state of knowledge; it should be recognized that as additional monitoring technologies are developed, more cost-effective approaches may be possible.

  - Reservoir pressure monitoring is mentioned. Casing/annular pressures should also be monitored. This is relatively easy and inexpensive and will likely be a preferred monitoring requirement for as long as the wells are not abandoned.

  - Monitor wells and seismic surveys are best for identifying locations where CO_2 is and is not. Volumetrically, they are inferential tools not directly quantifying the volume of CO_2 in place. If this uncertainty level is acceptable for emissions use, then the answers of 0 or large emissions annually will be equally likely. Other measurements would have to be called in. Surface seismic is too expensive to be used on an annual basis. The usual well bore to surface and cross-well seismic surveys do not have the spatial resolution to be accurate volume in place tools, except by inference. 4D seismic for detecting leakage is only likely to detect relatively large seepage; catastrophic releases are unlikely to be found by 4D seismic – you will know from the surface release.

  - Radioisotope monitoring is too specific in the technique. Borehole integrity measurements, of which isotope surveys are one type, may be appropriate. The DOE Guidance should focus on the entire class rather than just isotopes.

- Gravity at best tells where the gas is, and its accuracy degrades rapidly with depth. Surface gravity is not generally used for monitoring oil field operations anywhere in the world. Sleipner is at the shallowest depth that CO_2 is likely to be stored; conditions for gravity monitoring are unlikely to better anywhere else in the world. Surface gravity is very cheap, though. So if you told me to do two measurements annually, could I pick pressures and gravity and satisfy the requirements even though gravity is not likely to be successful? The problems with the specs cut both ways.

- The rest of the measurements in the cluster category have specific applications, especially during injection time frames, but are generally not volume estimation tools.

- Ecosystem impact analysis is present, but the way this is written it could be better as part of the general category of surface and near surface evidence for CO_2 seepage to the atmosphere. This could include CO_2 detection in air near the ground surface, satellite monitoring techniques, soil gas sampling, etc.

- With all of the emphasis on volume sensing techniques, the assumption seems to be that whatever escapes from the primary container will reach the atmosphere. At Weyburn and Gorgon, there are multiple seals above the primary container, so that reaching the atmosphere should not be a foregone conclusion. This will be the case for many storage sites.

- Storage will generally be more secure in deeper sites where there are less well penetrations, likely more chance for multiple seals and a longer pathway to the surface along which CO_2 can dissolve in water. Many monitoring techniques generally lose accuracy with depth. So, monitoring with surface seismic, EM, gravity, etc, if required, could actually drive one to shallower, less secure storage sites. For example, around Weyburn, there are less than $1/10^{th}$ as many wells to the deeper Winnipegosis formation underlying the field than there are in the Weyburn field, itself. Weyburn was marginal for seismic monitoring in the Midale reservoir. Seismic monitoring of the Winnipegosis is not likely to work but that does not mean that the Winnipegosis is a worse place to store CO_2. Basing the storage criteria on monitoring measurements may steer storage away from the most geologically desirable sites.

- Page 168: The Rating for post injection seepage is listed as listed as TBD. What is the practical implication for this? Does this mean storage projects cannot yet get credits? Because it will be difficult to develop an emission rating, DOE should rely on site-specific technology-based agreements between project proponents and regulators to determine whether carbon sequestration emission reductions are eligible to be registered.

- Emission factor ratings for agricultural and forestry sectors appear to be less rigorous than those for combustion.

- Page 253, 4th bullet: The word "rule" could be misleading. Instead of "one subentity rule," this could be called "one subentity: one output measurement," or something similar.

- Page 255, table 2.2: Pipeline transportation normalization factor should be barrel--miles, rather than barrels.

- Page 255, Table 2.2: Due to differences in refinery configurations, crude oil properties and refinery product specifications, refinery throughput is not an adequate metric for comparison of refinery emissions. It is important for DOE to recognize that emissions per barrel of crude throughput will vary greatly -- sometimes by a factor of two or three from refinery to refinery. Similarly, emissions per barrel for petroleum production operations should not be compared from one operation to another, since field characteristics vary widely, and the amount of energy required to produce oil may change as the field ages.

- Page 268, Section 2.4.5.6.3, last bullet: The last sentence is unclear when it says that only net "increases" can be registered. There should be clarification as to what these increases are relative to -- such as base period, common practice, etc.

- Page 271, Step 2: This step reinforces our comment regarding pages 146 and 148. It states that sales data will be the most easily referenced source of this information. We agree with this comment and believe it will make the results easily auditable as well.

- Page 272, Step 3: The calculation method given needs a set of parenthesis around the $(E_B/O_B) - (E_R/O_R)$ portion.

- Page 272: The DOE should specify when and how benchmark values will be updated. It may be cost-effective to update the benchmark every two or three years. However, the impact on emission reduction totals should be assessed.